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Article

Long-Term Decision on Wind Investment with Considering Different Load Ranges of Power Plant for Sustainable Electricity Energy Market

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Abstract: The aim of this paper is to provide a bi-level model for the expansion planning on wind investment while considering different load ranges of power plants in power systems at a multi-stage horizon. Different technologies include base load units, such as thermal and water units, and peak load units such as gas turbine. In this model, subsidies are considered as a means to encourage investment in wind turbines. In order that the uncertainties related to demand and the wind turbine can be taken into consideration, these effects are modelled using a variety of scenarios. In addition, the load demand is characterized by a certain number of demand blocks. The first-level relates to the issue of investment in different load ranges of power plants with a view to maximizing the investment profit whilst the second level is related to the market-clearing where the priority is to maximize the social welfare benefits. The bi-level optimization problem is then converted to a dynamic stochastic mathematical algorithm with equilibrium constraint (MPEC) and represented as a mixed integer linear program (MILP) after linearization. The proposed framework is examined on a real transmission network. Simulation results confirm that the proposed framework can be a useful tool for analyzing the investments different load ranges of power plants on long-term strategic decision-making.

Keywords: capacity investment; market power; wind resources; dynamic planning; stochastic approach

1. Introduction

Investment in renewable energy sources, including wind power plant, is of particular importance due to the increase in the efficiency of clean energy, and the need to reduce pollution and fuel consumption [1–3]. However, the production of wind resourced units involves an inherent uncertainty

and limited capacity, which alone may not be responsible for load growth in a power grid [4–7]. In addition, investment in wind resources may be less profitable than other technologies for investor due to budget constraints [8–12]. Consequently, there is a need to pay special attention to investing in renewable energy, including wind power, when carrying out generation expansion planning. Moreover, the possibility of investing in other technologies are taken into account in the model when generation expansion planning (GEP) is undertaken. However, this issue in previously presented models is often overlooked.

On the other hand, the analysis of the dynamic approach to this problem is of great importance due to the fact that yearly investment decisions (including capacity, location and time of construction) depend on investment decisions carried out in previous years [13–17]. As a result, in this article, we focus on a dynamic approach including renewable energy such as wind power in the grid used in the highest possible value. For this reason, investors will be encouraged to invest in the units while giving consideration to subsidies for new wind units. Whilst it is possible that the above incentives may not result in investment, other technologies that exploit peak load and base load units that consider various aspects (such as budget constraints, uncertainty and the limited capacity of wind turbines, etc.) during the planning stages, may be more profitable and therefore more attractive to investors.

In Figure 1, the effectiveness of the proposed GEP model is shown along with the above studies' shortcomings. The following points outline the important research that has been done in this field:

- The model presents more reliable and better results if those that are intended for the short-term market include the market clearing aspect, whereas those intended for the longer term take into account investment. Therefore, the investment problem in this paper is bi-level; however, those presented in [5,18–24] are not bi-level.
- In those models that have been proposed for market clearing, the supply function model in particular is a more accurate and realistic model when compared to others. Therefore, in this respect, a supply function model is used in the spot market whilst Refs. [25–29] make use of other models;
- In this paper, three different load range technologies, including base, peak and wind plant are considered as the candidate units for investment and each technology has different options for investment capacity. However, candidate units for investment in [5,21,25,27,30] are wind unit and in [14,19,20,22,26,31–39] are other technologies. In addition, in this paper, the subsidy is considered in order to stimulate investment in the wind unit. This approach is more in line with reality, whilst largely overlooked in previous cases;
- The proposed model is a dynamic one, whilst the dynamic nature of investment decisions has not been considered in papers concerning wind energy [3,25,40,41] and other technologies [19,20,22,26,32,34–39]. Therefore, the multi-period stochastic model consisting of transmission network constraints is presented here;
- In this network, consideration is given to the uncertainty in the generation of electricity from wind power along with demand consumption. These uncertainties are modeled by means of a scenario based approach.
- In addition, conventional producers are assumed to be competitive, i.e., they offer their respective productions at their marginal costs.

Considering the context above, contributions of this paper are as following:

- to propose a wind investment model considering different load ranges of power plants so that the best production technology in the optimized location are offered.
- to envelope a wind investment multi-stage model for sustainable electricity energy markets
- to provide a methodology to investigate subsidies in both planning and operating planning in a network-constrained electricity market as a game-theoretic model.
- To implement the proposed model to Mazandaran Regional Electric Company (MREC) as a real power network and comprehensively analyze the related results.

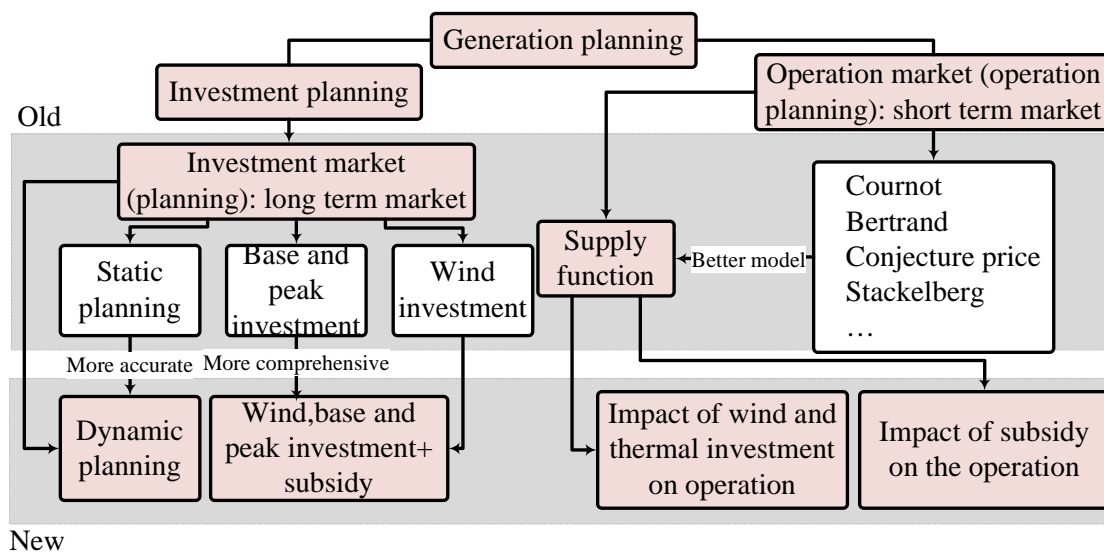


Figure 1. Block diagram illustrating the effectiveness of investment and planning.

2. Planning Features

Dynamic multi-stage property: Planning in this article is done for 10 stages. Each stage can include one to several years depending on the terms planner. The annual discount rate of each stage in the dynamic approach is assumed to be 8.7%. Non-anticipativity issues should be analyzed according to the uncertainty of the demands and wind turbine production, as shown in Figure 2, combined with the dynamic approach of GEP.

Demand model property: the demand blocks are obtained from a stepwise approximation of the load-duration curve, as illustrated in Figure 2a. It is assumed that the per-stage demand is specified with three different demand blocks; namely peak, shoulder and off-peak. Annual growth of demands is assumed to be 6.2%. The weighting factors associated with each demand block (peak, shoulder and off-peak) are assumed to be 20%, 50% and 30%, respectively. In each year of the planning period, the weighting factor of the off-peak and shoulder blocks are considered to be 25% and 60% respectively of the associated forecasted peak demand. For the sake of simplicity, each demand considers one bid per block. For MREC demand, three uncertainties are considered, having the same probabilities as those shown in Figure 2b.

Investment technologies property: In this paper, three different load ranges of power plants including base, peak and wind units are considered for investment. Base technologies have relatively low operation costs but high investment costs due to supplying grid demand during all hours of the day. However, peak technologies, whilst also having low operation costs with high investment costs, only supply the grid during hours of peak demand.

In this article, it is assumed that the grid includes the construction of wind turbines. Construction of these units involves higher investment costs than the peak and base units; however, it is assumed that the operation cost of wind turbines units is zero. Renewable energy such as wind resources are usually characterized by uncertainty. The uncertainty of wind turbines can be modeled using a set of scenarios. To represent the uncertainty related to wind production, only three wind intensity factors are considered, despite the fact that a larger number of scenarios may easily be considered for a typical wind turbine in this model. Limiting the number of intensity factors prevents an increase in the computational complexity and corresponding time to solve the mathematical model by means of software simulation. Therefore, nine uncertainties are obtained with respect to three uncertainties of demand.

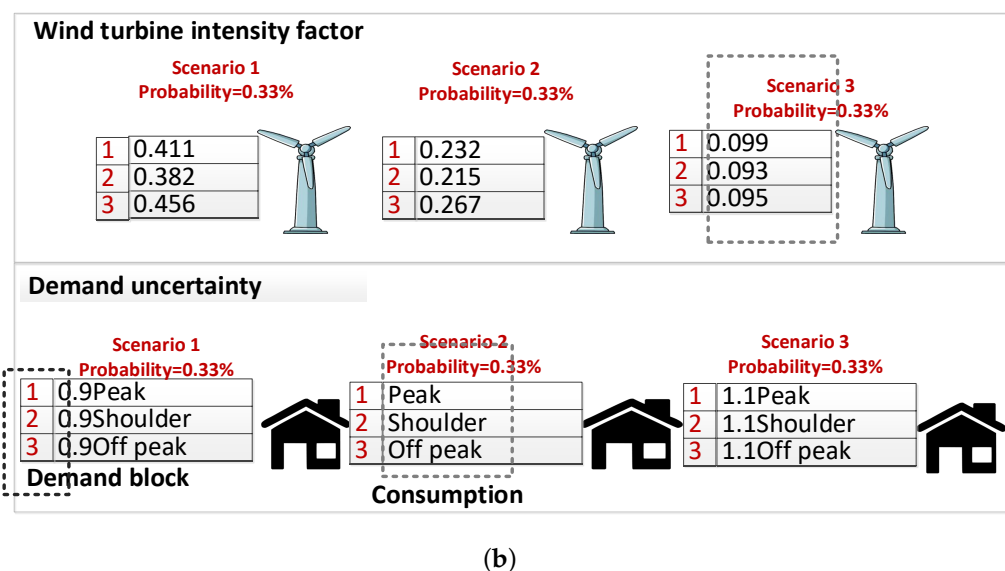
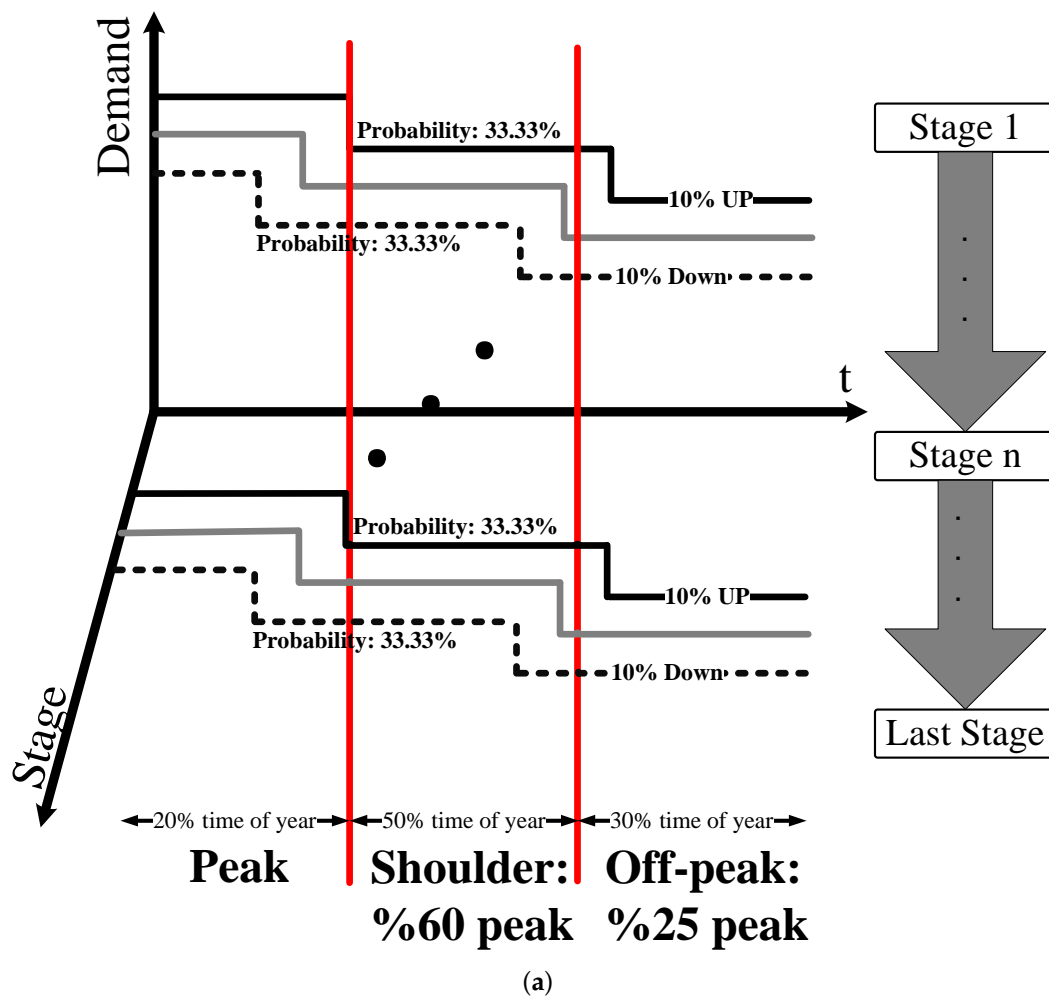


Figure 2. Features of demand and wind turbine. (a) piecewise approximation of the load duration curve for the planning year at a particular bus; (b) the uncertainty of demand and wind turbine.

The modeling of wind turbine and converter: the Kinetic energy produced by wind is converted into mechanical power by the wind turbine rotor:

$$P_{wt} = 0.5\rho\pi R^2 V^3 = 0.5\rho\pi R^2 \left(\frac{R}{\lambda}\right)^3 (W_R)^3, \quad (1)$$

$$\lambda = \frac{W_R R}{V}, \quad (2)$$

$$P_{mec} = C_p(\lambda, \beta) P_{wt} = 0.5 C_p(\lambda, \beta) \rho \pi R^2 \left(\frac{R}{\lambda}\right)^3 (W_R)^3. \quad (3)$$

Equations (1)–(3) present equations of wind turbine modelling. Equation (1) presents the output power for wind turbine so that ρ and R are the air density (kg/m^3) and the blade radius (m) accordingly. In addition, V , W_R as well as λ present the wind speed (m/s), rotor speed (rad/s) and the turbine tip-speed ratio, respectively [42]. The relation between turbine mechanical power (P_{mec}) and available power (P_{wt}) is represented by Equation (3) while C_p and β are power coefficient and pitch angle, respectively.

Non-anticipativity property: it should be noted that there is an issue of non-anticipativity nature in the problem of stochastic multi-stage modelling [43]. Figure 3 shows the different states relating to this issue. If the scenarios considered in the model are independent and different from one another at all stages, these provisions should not be applied to the programming (Mode 1, Figure 3). The multi-stage problems that include uncertainty have two modes, if uncertainties in the scenarios being considered are the same in the process of multi-stage models. The constraints related to non-anticipativity properties should be applied to the model (Mode 3, Figure 3) if the problem of stochastic multi-stage is solved by optimization algorithms, such as heuristic algorithms, in order that each iteration results in a different optimal solution. In addition, applying non-anticipativity constraints to the program is optional, if GAMS solvers such as MILP, LP, and NLP are used that result in the same optimal solution in repeated results (iterations). As a result of these issues around optimization, the same result in the optimal solution is obtained for scenarios that are similar in some of the steps (Mode 2, Figure 3). Therefore, applying the non-anticipativity conditions to the program tends to increase the complexity of the model and the corresponding calculations' volume; however, it has no effect on providing the optimal solution. This issue should be considered in the simulation results only to ensure the correct program process; it can be ignored in a model for simplifying purposes and to achieve less computation and complexity. In this article, the provisions of the non-anticipativity properties can be omitted due to the fact that the defined scenarios are independent of each other and they do not have any similarities with cases spanning a 10-year planning period.

The aforementioned is similar to Mode 1 from Figure 3. For example, the dynamic stochastic [20,44] is similar to the work of this paper and case 1 of Figure 3 and the expressed model in [20] is similar to Mode 3 of Figure 3. The first-level variables, which correspond to the installed generation capacity of the investing agent, will not be stochastic variables, however, since a generation company can only make one investment decision due to the fact that it is impossible to know which scenario is going to occur in reality.

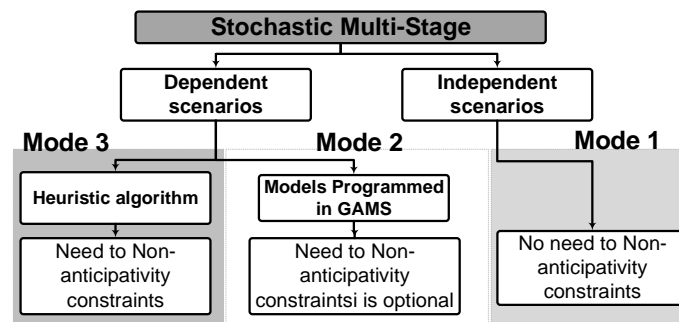


Figure 3. Three different cases for the non-anticipativity condition in a multi-stage stochastic problem.

3. The Proposed Algorithm

This idea is solved by the algorithm presented in Figure 4. The planning carried out with the aim of maximizing the profits of the investment in the wind unit along with different load ranges, power plants including peak and base technologies, and investment in wind units that includes subsidies and grants to encourage investment is invested in the first year. New units are operated in subsequent years as existing units in the network. In the next stage, the intention is to minimize the operation cost so that the output at this stage is the market-clearing results, which includes market-clearing prices, unit production and consumption. This procedure is carried out for the next blocks in the first year. Overall, the benefits of investment and operation are maximized as a result of this planning. In Figure 4, N_r , N_w , N_t , N_{wu} and N_{thu} are number of years, scenarios, time block, new wind units and new thermal units in the planning year, respectively. In addition, more information about bi-level modelling can be figured out in [19,43–45]. In addition, to perceive multi-stage planning, Ref. [14] is useful.

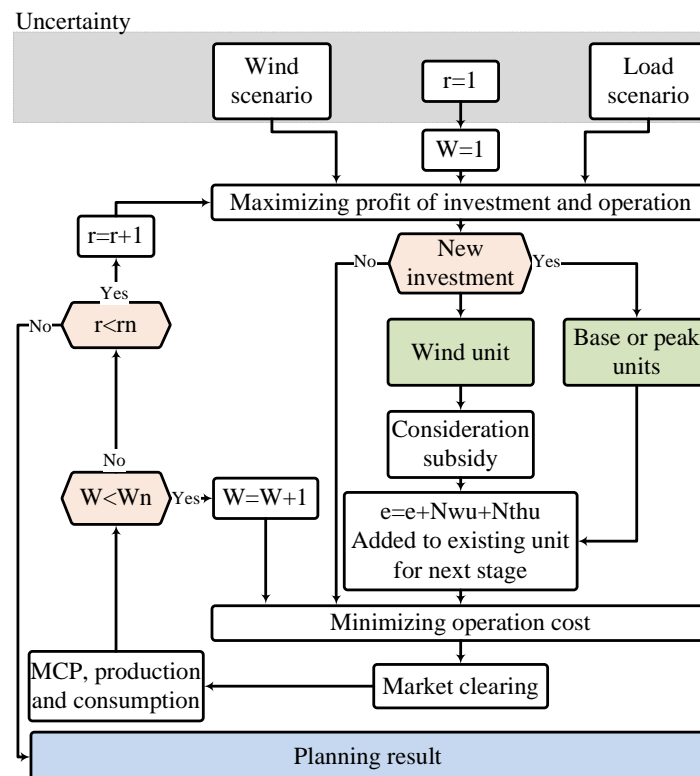


Figure 4. The algorithm for solving the proposal idea.

3.1. Inputs and Outputs

Figure 5 shows the input and output of each stage and stage to stage. The first-level includes 10 stages in which each stage includes a set of market-clearing issues for different scenarios and time demand blocks. The input of the first level for each stage includes input related to investment in different load ranges of power plants k_s^{TH} , CS_s^{TH} , $c_n^{invyear}$, c_n^{inv} , X_n^{Wmax} , S and the general input N_t^h , γ_{tw} , P_i^{ESmax} , CS_i^{ES} , f .

First-level variables include X_{ys}^{TH}/X_{yn}^W , u_{ysh}^{TH}/u_{ynl}^W , and these have a certain effect in the second-level and are therefore considered to be second-level inputs. In addition, the second level includes the general inputs P_i^{ESmax} , $d_{yjt看}$, B_{nm} , and F_{nm}^{max} . The output of the second-level are variables $P_{ystw}^{TH}/P_{yitw}^{Es}/P_{yntw}^W$, $P_{yy'stw}^{TH}/P_{yy'n,tw}^{TH}/P_{yy'n,tw}^{WY}$, and θ_{ytnw} . These variables are also the variables of first-level. First-level input of each stage to the next stage includes variables P_i^{ESmax} , $d_{yjt看}$, B_{nm} , F_{nm}^{max} and the second-level input of the previous stage includes variables \bar{G}^{theu} .

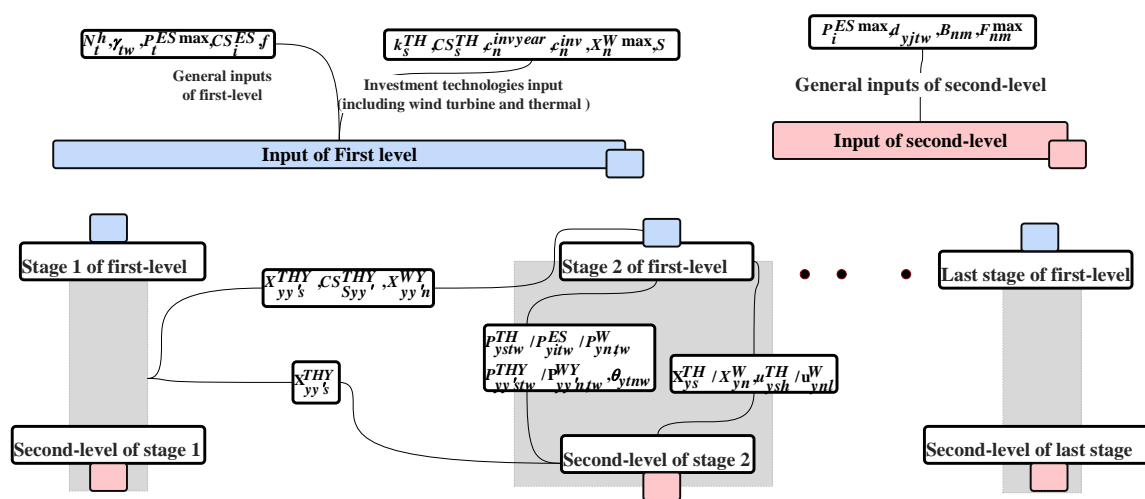


Figure 5. Input and output of each stage and stage to stage.

3.2. Converting Two Level Model to One Level Model

The market and the proposed algorithm are expressed using the bi-level model to implement the proposed ideas in this article. This bi-level model can be solved by heuristic algorithms, GAMS solvers and so forth. The GAMS solvers are used to solve the model proposed in this paper. For this purpose, the bi-level model is converted to a one-level problem and then the optimal solution is obtained using the available solvers, as shown in Figure 6. The second-level problem has constraints including DC power flow, limitations of unit production, and balance between production and consumption. Therefore, the second-level problem is a linear problem and therefore convex. Thus, karush kuhn tucker (KKT) conditions can be used to convert the bi-level problem into a one-level problem. Furthermore, complimentary constraints obtained from KKT conditions are linear when using the theory of big M. The resulting mathematical model becomes a problem of MILP after linearization of the nonlinear relationships and therefore it is solvable by MILP solvers in GAMS.

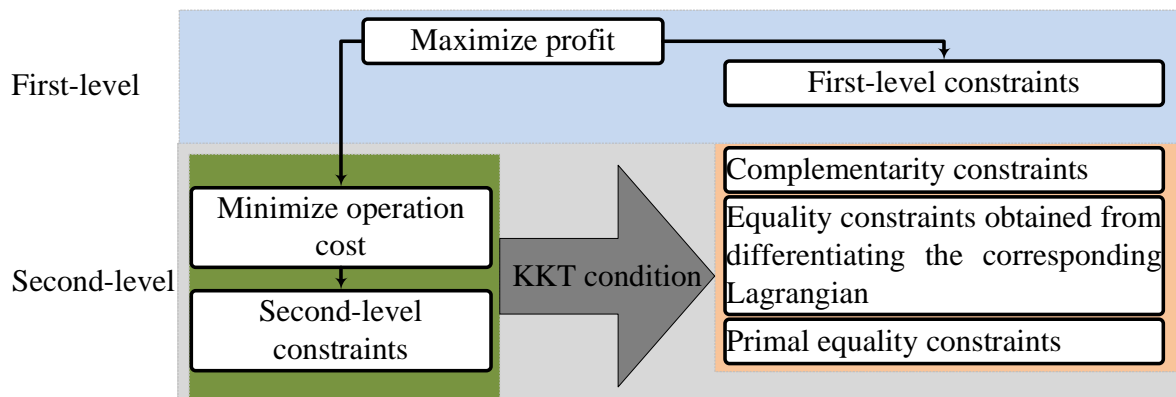


Figure 6. Converting the bi-level problem into one-level problem.

4. Mathematical Formulation

In the following sub-sections, the mathematical formulation of this paper is presented. In order to introduce the model, we define the following sets, parameters and decision variables.

4.1. The Bi-Level Model

The first-level represents the investment problem of the conventional producers who are seeking to maximize the present value of the total profit of investment (whether base or peak) and of operation. Due to the dynamic nature of the planning problem, dynamic dependency constraints exist in the first-level. The second-level problem represents the market-clearing. The clearing of the market for any given operating condition is represented as an optimization problem that identifies the operating decisions that maximize social welfare. In this model, maximizing the social welfare is equivalent to minimizing the generation cost. The market clearing problem is constrained by the DC power flow equations, transmission network limitations and units' capacity limits. The output of the second-level problem is nodal prices (dual variables associated with the power balance constraints), which are fed back to the first-level.

The multi-period stochastic investment problem is formulated using the following bi-level model, which comprises the first-level problem, i.e., Equations (4)–(12), and a collection of second-level problems, i.e., Equations (14)–(20).

First level: The objective function (i.e., Equation (4)) is the present value of the projected profit (expected revenue offset by investment cost) in the planning horizon, which comprises three terms. The first and second terms of profit function (i.e., Equation (4)) are associated with the investment cost of new units, including peak and base technologies and wind units, respectively. The third term of the profit function (i.e., Equation (4)) is the expected profit obtained by selling energy in the spot market. Equation (5) states that investment options for new base or peak units are only available in discrete blocks, just as that of wind investment modelled through Equation (6). These equations impose the constraint that only one technology is binding and determines the new technology to be installed at each bus of the system. It should be noted that, based on Equations (5) and (6), the producer can either open exactly one new plant each year, or choose one option for installing it. These constraints define the maximum capacity of wind units along a multi-stage horizon that can be constructed in each location with wind power facilities. The dynamic dependency constraints on the base or peak investment decision variables are represented in Equations (7) and (8), while Equation (9) is related to the dynamic dependency constraints applicable to the wind investment. The new units are operated in the next years as existing units in the network (Equations (7) and (9)). Equation (8) is related to the marginal cost of a new base or peak units in subsequent years. Equation (10) enforces that wind generation at each bus scenario is limited to the installed wind power at the corresponding bus multiplied by a factor that models the wind intensity at that bus and scenario. Equation (11) as the dynamic dependency constraint shows wind production constraints in the years after the establishment

of new units. The available budget limitation is represented in Equation (12) for investment in wind and new thermal units.

Second level: The market clearing problems are represented by the negative social welfare expressed Equations (13)–(20). Equation (14) represents the energy balance at each bus, this being the associated dual variables' LMPs or nodal prices. Equations (15)–(19) impose power bounds for blocks of generation constraints, power flow and angle bounds. Equation (20) fixes the voltage angle at the reference bus. Dual variables are indicated at the relevant constraints following a colon:

First level objective function:

$$\begin{aligned}
 \min \quad & \sum_y \left(\frac{1}{1+f} \right)^y \sum_s X_s^{\text{TH}} k_s^{\text{TH}} \\
 & + \sum_y \left(\frac{1}{1+f} \right)^y \sum_t (1-S) c_n^{\text{inv}} X_n^{\text{W}} \\
 & - \sum_y \left(\frac{1}{1+f} \right)^y \sum_t N_t^h \sum_w \gamma_{tw} \\
 & \sum_n P_{n,tw}^{\text{W}} \lambda_{n,tw} \\
 & + \sum_n \sum_{y'} P_{yy'n,tw}^{\text{WY}} \lambda_{n,tw} \\
 & + \sum_s P_{ystw}^{\text{TH}} \lambda_{n,tw} - \sum_s P_{ys,tw}^{\text{TH}} \text{CS}_s^{\text{TH}} \\
 & + \sum_s \sum_{y'} P_{yy'stw}^{\text{THY}} \lambda_{n,tw} \\
 & - \sum_s \sum_{y'} P_{yy'stw}^{\text{THY}} \text{CS}_{yy'}^{\text{THY}} \\
 & + \sum_i P_{yitw}^{\text{ES}} - \sum_i P_{yitw}^{\text{ES}} \text{CS}_i^{\text{ES}}.
 \end{aligned} \tag{4}$$

First level subjected to:

Subject to:

$$X_{ys}^{\text{TH}} = \sum_h u_{ysh}^{\text{TH}} X_{ysh}^{\text{TH}}, \sum_h u_{ysh}^{\text{TH}} = 1, u_{ysh}^{\text{TH}} \in \{0, 1\} : \forall y, \forall s, \forall h, \tag{5}$$

$$X_{yn}^{\text{W}} = \sum_L u_{ynl}^{\text{W}} X_{ynl}^{\text{W}}, \sum_L u_{ynl}^{\text{W}} = 1, u_{ynl}^{\text{W}} \in \{0, 1\} : \forall y, \forall l, \forall n, \tag{6}$$

$$X_{yy's}^{\text{THY}} = X_{ys}^{\text{TH}}, \forall y, y' \in \{X_{yy'}^{\text{TH}} > 0, y > y'\}, \forall s, \tag{7}$$

$$\text{CS}_{yy'}^{\text{THY}} = \text{CS}_s^{\text{TH}}, \forall y, y' \in \{X_{yy'}^{\text{TH}} > 0, y > y'\}, \forall s, \tag{8}$$

$$X_{yy'n}^{\text{WY}} = X_{yn}^{\text{W}}, \forall y, y' \in \{X_{yn}^{\text{W}} > 0, y > y'\}, \forall n, \tag{9}$$

$$P_{yn,tw}^{\text{W}} \leq K_{n,tw} X_{yn}^{\text{W}} : \forall y, \forall n, \forall t, \forall w, \tag{10}$$

$$0 \leq P_{yy'n,tw}^{\text{WY}} \leq X_{yy'n}^{\text{WY}}, \forall y, y' \in \{X_{yn}^{\text{W}} > 0, y > y'\}, \forall t, \forall n, \forall w, \tag{11}$$

$$\sum_y \left(\frac{1}{1+f} \right)^y \left(\sum_n (1-S) C_n^{\text{inv}} X_n^{\text{W}} + \sum_s k_s^{\text{TH}} X_{ys}^{\text{TH}} \right) \leq k^{\text{max}}. \tag{12}$$

Second level objective function:

$$\begin{aligned}
 \min \quad & \sum_i P_{yitw}^{\text{ES}} \text{CS}_i^{\text{ES}} + \sum_s P_{ystw}^{\text{TH}} \text{CS}_s^{\text{TH}} \\
 & + \sum_s P_{yy'stw}^{\text{THY}} \text{CS}_{yy'}^{\text{THY}}, \forall y, \forall t, \forall w.
 \end{aligned} \tag{13}$$

Second level subjected to:

$$\begin{aligned} & \sum_i \sum P_{yitw}^{ES} + \sum_s \sum P_{ystw}^{TH} + \sum P_{yy'n,tw}^{WY} \\ & + \sum P_{yy'stw}^{THY} + P_{yntw}^W - \sum_m B_{nm}^{PU} S_b(\theta_{yntw} - \theta_{ytmw}) \end{aligned} \quad (14)$$

$$\begin{aligned} & = \sum_j d_{yitw} : \lambda_{ntw} \quad \forall n, \forall t, \forall y, \forall w, \\ & 0 \leq P_{yitw}^{ES} \leq P_{yi}^{ESmax} : \phi_{yitw}^{\min}, \phi_{yitw}^{\max} \quad \forall y, \forall i, \forall t, \forall w, \end{aligned} \quad (15)$$

$$0 \leq P_{ystw}^{TH} \leq X_{ys}^{TH} : \mu_{ystw}^{\min}, \mu_{ystw}^{\max} : \forall y, \forall s, \forall t, \forall w, \quad (16)$$

$$0 \leq P_{yy'stw}^{THY} \leq X_{yy's}^{THY} : \mu_{yy'stw}^{THYmin}, \mu_{yy'stw}^{THYmax} \quad (17)$$

$$\begin{aligned} & \forall y, y' \in \{X_{y's}^{TH} > 0, y > y'\}, \forall t, \forall s, \forall w, \\ & -F_{nm}^{\max} \leq B_{nm}^{PU} S_b(\theta_{yntw} - \theta_{ytmw}) \leq F_{nm}^{\max} : \end{aligned} \quad (18)$$

$$v_{ytnmw}^{\min}, v_{ytnmw}^{\max} \quad \forall n, \forall m, \forall t, \forall y, \forall w, \quad (19)$$

$$-\pi \leq \theta_{yntw} \leq \pi : \zeta_{yntw}^{\min}, \zeta_{yntw}^{\max}, \quad \forall n, \forall t, \forall y, \forall w, \quad (19)$$

$$\theta_{yntw} = 0 : \zeta_{yntw}^1 \quad n = 1, \forall t, \forall y, \forall w. \quad (20)$$

MPEC

The bi-level problem (i.e., Equations (4)–(20)) can be converted to a single level problem (MPEC) by enforcing KKT conditions to the second-level problems [14,20,27]. These are represented by Equations (21)–(35). This transformation is possible because the lower-level problems are continuous and linear (and thus convex). The resulting problem is an MPEC, which includes nonlinearities in the objective function and in the complementarity conditions. These nonlinearities could be transformed into equivalent linear terms. Using this linearization, the investment problem can be finally expressed by the following MILP problem, as presented in the algorithm in Figure 4. To find a linear expression for $\sum_{n \in \Omega^N} P_{n,tw}^W \lambda_{n,tw} + \sum_s P_{ystw}^{TH} \lambda_{n,tw} + \sum_i P_{yitw}^{ES} \lambda_{n,tw} + \sum_s \sum_{y'} P_{yy'stw}^{THY} \lambda_{n,tw}$ in Equation (4), we use the strong duality theorem and some of the KKT equalities [31]. The strong duality theorem says that, if a problem is convex, the objective functions of the primal and dual problems have the same value at the optimum.

Objective function of MPEC:

$$\begin{aligned} & \min \sum_y \left(\frac{1}{1+f} \right)^y \sum k_s^{TH} X_{ys}^{TH} + \sum_y \left(\frac{1}{1+f} \right)^y \sum_t (1-S) C_n^{\text{inv}} X_{yn}^W \\ & - \sum_y \left(\frac{1}{1+f} \right)^y \sum_t N_t^h \sum_w \gamma_{tw} \\ & \left(\begin{aligned} & \sum \lambda_{yn,tw} \sum d_{yj,tw} - \sum_{i \in \Omega^N} \phi_{yitw}^{\max} \\ & - \sum_n v_{ytnmw}^{\min} F_{nm}^{\max} - \sum_n v_{ytnmw}^{\max} F_{nm}^{\max} - \sum_n (\zeta_{yntw}^{\min} + \zeta_{yntw}^{\max}) \pi \\ & - \sum \sum_i P_{yitw}^{ES} CS_i^{ES} - \sum \sum_s P_{ystw}^{TH} CS_s^{TH} - \sum_s \sum_{y'} P_{yy'stw}^{THY} CS_{yy'}^{THY} \end{aligned} \right). \end{aligned} \quad (21)$$

MPEC subjected to:

- First-level constraints: Equations (5)–(12).
- Primal equality constraints equal to second-level: Equations (14)–(20).
- Equality constraints obtained from differentiating the corresponding Lagrangian:

$$CS_i^{ES} - \lambda_{yntw} + \phi_{yitw}^{\max} - \phi_{yitw}^{\min} = 0 : \forall y, \forall i, \quad (22)$$

$$CS_s^{TH} - \lambda_{yntw} + \mu_{ystw}^{\max} - \mu_{ystw}^{\min} = 0 : \forall y, \forall s, \quad (23)$$

$$CS_{syy'}^{THY} - \lambda_{yntw} + \mu_{yy'stw}^{THY\max} - \mu_{yy'stw}^{THY\min} = 0 : \forall y, \forall s, \quad (24)$$

$$\begin{aligned} \sum_m B_{nm}^{PU} S_b(\lambda_{ytnw} - \lambda_{ytmw}) + \sum_m B_{nm}^{PU} S_b(V_{ytnmw}^{\max} - V_{ytmnw}^{\max}) \\ + \sum_m B_{nm}^{PU} S_b(V_{ytnmw}^{\min} - V_{ytmnw}^{\min}) + \zeta_{ytnw}^{\max} - \zeta_{ytnw}^{\min}. \end{aligned} \quad (25)$$

- Complimentary constraints by KKT:

$$0 \leq P_{ystw}^{TH} \perp \mu_{ystw}^{\min} \geq 0 \quad \forall y, \forall t, \forall i, \forall w, \quad (26)$$

$$0 \leq P_{yitw}^{EX} \perp \phi_{itw}^{\min} \geq 0 \quad \forall y, \forall i, \forall t, \forall w, \quad (27)$$

$$0 \leq (X_{ys}^{TH} - P_{ystw}^{TH}) \perp \mu_{ystw}^{\max} \geq 0 \quad \forall y, \forall s, \forall t, \forall w, \quad (28)$$

$$0 \leq P_{yy'stw}^{THY} \perp \mu_{yy'stw}^{THY\min} \geq 0 \quad \forall y, \forall s, \forall t, \forall w, \quad (29)$$

$$0 \leq (X_{yy's}^{THY} - P_{yy'stw}^{THY}) \perp \mu_{yy'stw}^{THY\max} \geq 0 \quad \forall y, \forall s, \forall t, \forall w, \quad (30)$$

$$0 \leq (P_i^{EX\max} - P_{yitw}^{EX}) \perp \phi_{itw}^{\max} \geq 0 \quad \forall y, \forall i, \forall t, \forall w, \quad (31)$$

$$0 \leq [F_{nm}^{\max} - B_{nm}^{PU} + S_b(\theta_{ytnw} - \theta_{ytmw})] \perp V_{ytnmw}^{\max} \geq 0 \quad \forall y, \forall t, \forall n, \forall m, \forall w, \quad (32)$$

$$0 \leq [F_{nm}^{\max} + B_{nm}^{PU} + S_b(\theta_{ytnw} - \theta_{ytmw})] \perp V_{ytnmw}^{\min} \geq 0 \quad \forall y, \forall t, \forall n, \forall m, \forall w, \quad (33)$$

$$0 \leq (\pi - \theta_{ytnw}) \perp \zeta_{ytnw}^{\max} \geq 0 \quad \forall y, \forall t, \forall n, \forall w, \quad (34)$$

$$0 \leq (\pi + \theta_{ytnw}) \perp \zeta_{ytnw}^{\min} \geq 0 \quad \forall y, \forall t, \forall n, \forall w. \quad (35)$$

Equations (26)–(35) are linearized as follows [14,27]:

The complementarity condition

$$0 \leq a \perp b \geq 0 \quad (36)$$

can be replaced by

$$a \geq 0, b \geq 0, a \leq \tau M, b \leq (1 - \tau)M, \tau \in \{0, 1\}, \quad (37)$$

where M is a large enough constant.

5. Case Studies

In this section, the efficiency of the proposed framework is examined through a real case study. The case study is the MAZANDARAN regional electric company (MREC) transmission network as a section of an IRAN interconnected power system.

Case Study: MREC Network

A single-line diagram representing the MREC transmission network is shown in Figure 7 [14,46]. The candidate buses for construction of the new base and peak units are assumed to be AMOL,

ALIABAD and NEKA, all of which operate at 230 kV. In addition, buses ROYAN and DARYASAR are considered as candidate sites for construction of the new wind units. The maximum wind capacity that can be installed at these buses is equal to 300 MW for each bus.

The cases considered for the MREC transmission network are characterized in Table 1. The second column of this table gives the type of planning (static or dynamic) and columns 3 and 4 identify the subsidy percentage and the available budget, respectively. In Cases 1–4, the type of planning is static, while Cases 5–8 refer to dynamic cases. In addition, in Cases 2, 4, 6 and 8, consideration has been made of the impact of subsidy on the wind investment. In these cases, the subsidy percentage is assumed to be 20%. The proposed model is solved using Solver XPress software GAMS (IBM ILOG CPLEX Solver, 11.0.1, Armonk, NY, USA) [47].

Table 1. The cases considered for the MREC transmission network.

Cases	Planning	Subsidy (%)	Budget (M\$)
#1	Static	0	15.0
#2	Static	20	15.0
#3	Static	0	150
#4	Static	20	150
#5	Dynamic	0	150
#6	Dynamic	20	150
#7	Dynamic	0	1500
#8	Dynamic	20	1500

Case #1 total thermal investment is equal to 700 MW in the peak technology due to budget limitations and offset by their investment cost with respect to base technology. In this case, the total capacity added by the producer in the planning horizon has been established at 900 MW, resulting in the producer investing 200 MW in the wind technology and 700 MW in the peak technology. In this case, total thermal investment is attributable to peak technology due to budget limitation and less their investment cost with respect to base technology. The existing units supply 9.78 MMWh of the energy consumed by the network and thereby play an important role in the provision of energy to the MREC network;

Case #2 Investment in wind units in this case is increased by 50 MW compared with Case #1 due to a 20% subsidy. In addition, the investment cost of wind units is the same as Case #1. In this case, the production of wind units has increased by 25.58%. Therefore, the net profit in Case #2 has increased by 18.44% with respect to Case #1;

Case #3 The total capacity added by the producer in Case #3 has increased by 450 MW compared with Case #1 by increasing the budget from 15 M\$ to 150 M\$. Investment in wind units in this case has increased by 400 MW compared with the Case #1 due to an increase in the budget. In addition, the total thermal investment is base technology so that 750 MW is added to the MREC network. In Case #3, the production of wind and new thermal units have been increased by 201.62% and 98.15% compared with Case #1, respectively. In addition, the net profit in the planning horizon has been obtained equal to 108 M\$ that it has been increased by 389.35% with respect to Case #1;

Case #4 In Case #4, investment in wind and thermal units is the same as Case #3. In this case, subsidy has no effect on wind investment because the total capacity of wind units added to network is the same as in Case #3. In addition, the production of different units is the same as Case #3. However, the investment cost of wind units has decreased by 20% due to the 20% subsidy. As a result, the investor's net profit has increased by 5.56% compared with Case #3;

Case #5 In this case, the total capacity added by the producer in the planning duration has been determined to be 1200 MW, resulting in the producer investing 500 MW in the base technology and 700 MW in the peak technology, while no wind unit was constructed in the MREC network. This is the result of the desire to invest in units that have a lower investment cost due to the

budget limitations. In addition, distribution of the investment are as follows: 200 MW on peak technology in the first year, 500 MW on base technology in the fifth year, 250 MW on peak technology in the eighth year and 250 MW on peak technology in the ninth and tenth years. Due to lack of generation in the western region, the total capacity has been constructed in AMOL located in this region.

Case #6 All output of Case #6 is the same as Case #5; consequently, the consideration of a 20% subsidy has no influence on the desire to invest in wind units. It can be observed that the 20% subsidy is not enough to encourage investment in wind units and therefore the capacity of wind units is zero in this network.

Case #7 In Case #3, the total capacity added by the investor has increased by 1400 MW compared with Case #5 and Investment in wind units in this case have been increased by 600 MW compared with the Case #1. In addition, total thermal investment is base technology so that 2000 MW base technologies are added to the MREC network. In Case #7, the production of new thermal units has been increased by 75.89% compared with Case #5, while the production of existing units decreased by 81.04%. In addition, the production of wind units has been increased from 0 MMWh to 12.97 MMWh with respect to Case #5. Thus, the total net profit in the planning duration is predicted to be 973.28 M\$, an increase of 188.86% with respect to Case #5.

Case #8 In this case, investment in wind and thermal units, and the production of different units, is the same as Case #7. However, investment cost of wind units has been decreased by 20% due to the 20% subsidy. As a result, the investor's net profit has been increased by 9.62% compared with Case #3.

Figure 8 shows the result of GEP for MREC network for: (a) the produced power, (b) the produced energy, and (c) investment. Figure 9 depicts the percentages related to the budget, investment cost and total net profit for each case in the planning period. For example, the percentage related to the budget, investment cost and total net profit in the Case #1 are shown to be equal 29%, 29% and 42%, respectively, corresponding to 15, 14.99 and 22.07 when expressed in M\$. The net profit in Case #5 and Case #6 in the dynamic approach has been increased by 26.19% and 12.77% compared to Case #1 and Case #2 in the static approach, respectively. Furthermore, the investment cost has been decreased by 17.24% and 11.11%, respectively. In addition, the net profit in Case #3 and Case #4 in the static approach has been increased by 14.28% and 9.68% compared to Case #7 and Case #8 in the dynamic approach, respectively. Furthermore, the investment cost has been decreased by 14.28% and 12%, respectively. Therefore, it can be seen that the percentage profit as a result of increasing the available budget for both static and dynamic planning. For lower budgets, the percentage profit yielded by the dynamic approach exceeds that of the static approach so that the investment cost in the former is less than in the latter. However, if a larger budget is available, the percentage profit yielded by the static approach exceeds that of the dynamic approach, whilst the former requires a lower investment. The use of a subsidy can increase investor profit if it stimulates investment in wind technologies. In addition, the investment cost decreases in these cases. It can be seen that the degree of investment increases when the dynamic approach is applied, when compared to the static approach. Moreover, consideration of the dynamic versus static trade-offs when the planning of generation capacity leads to accurate and realistic results in the expansion planning.

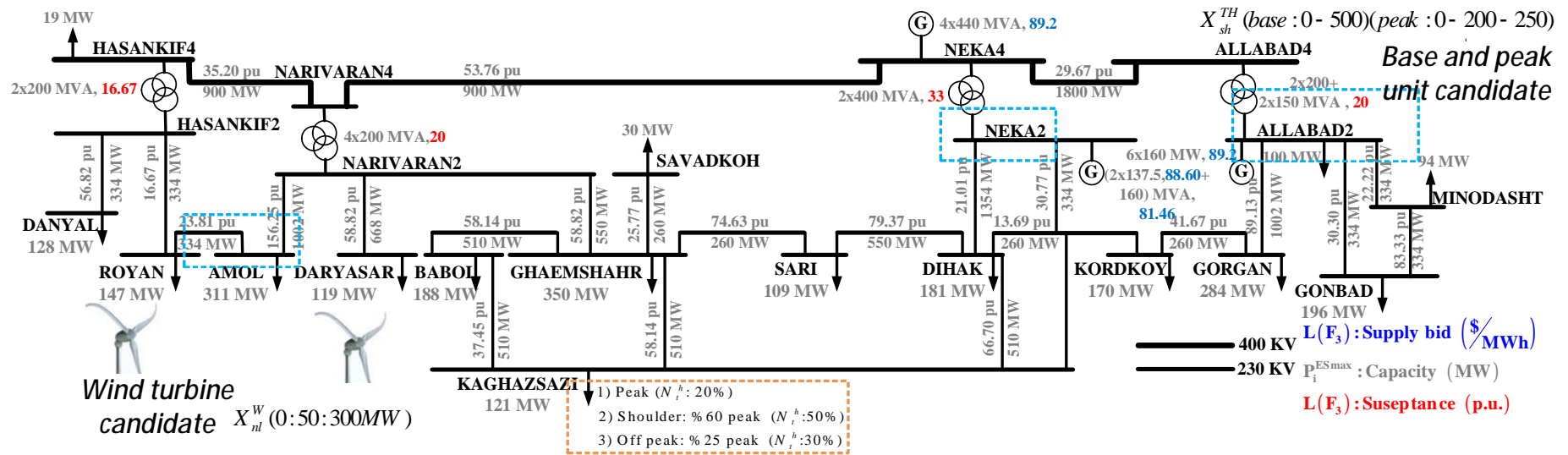


Figure 7. Single-line diagram of the MAZANDARAN Regional Electric Company (MREC) transmission network.

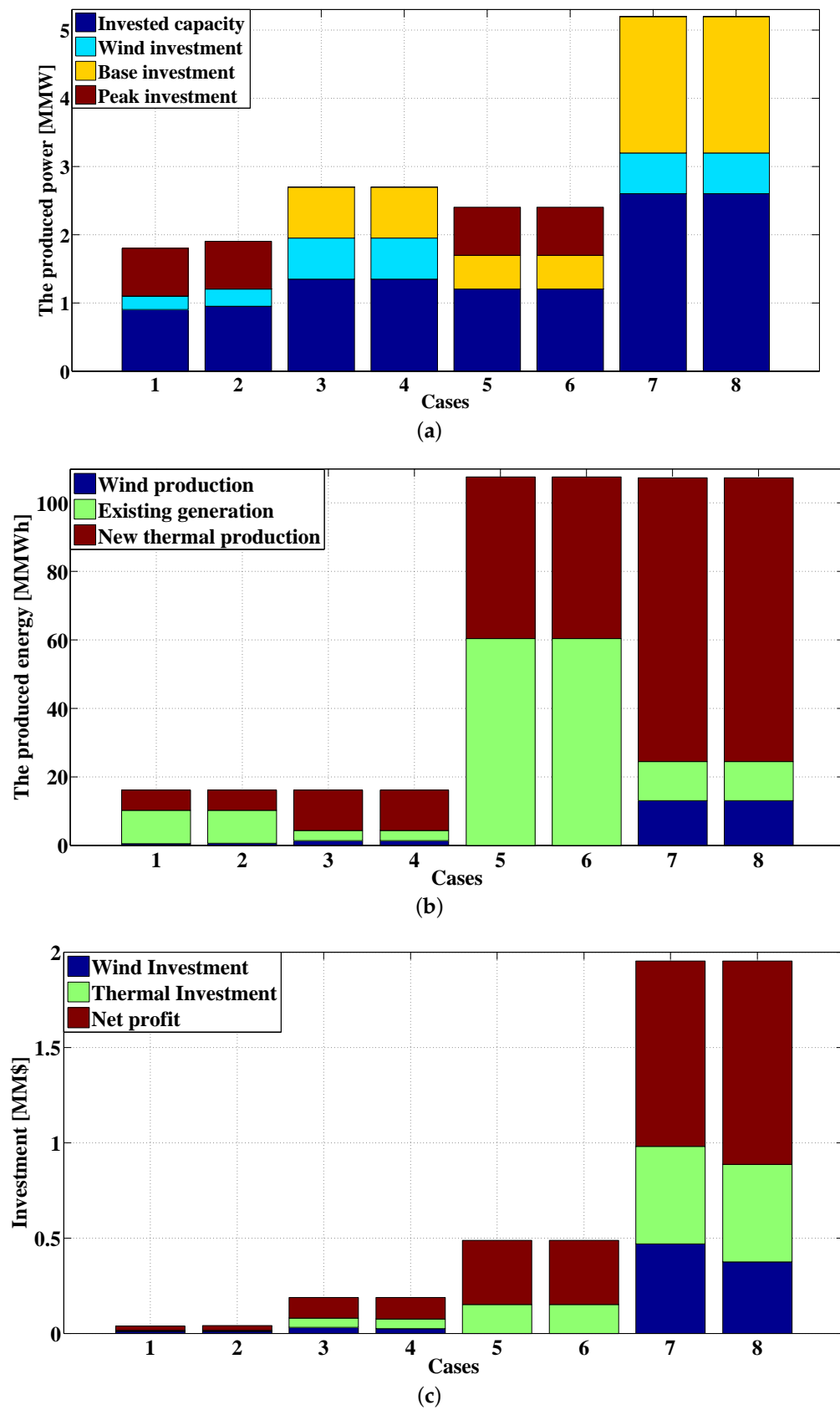


Figure 8. The result of GEP for MREC network. (a) the produced power; (b) the produced energy; (c) investment.

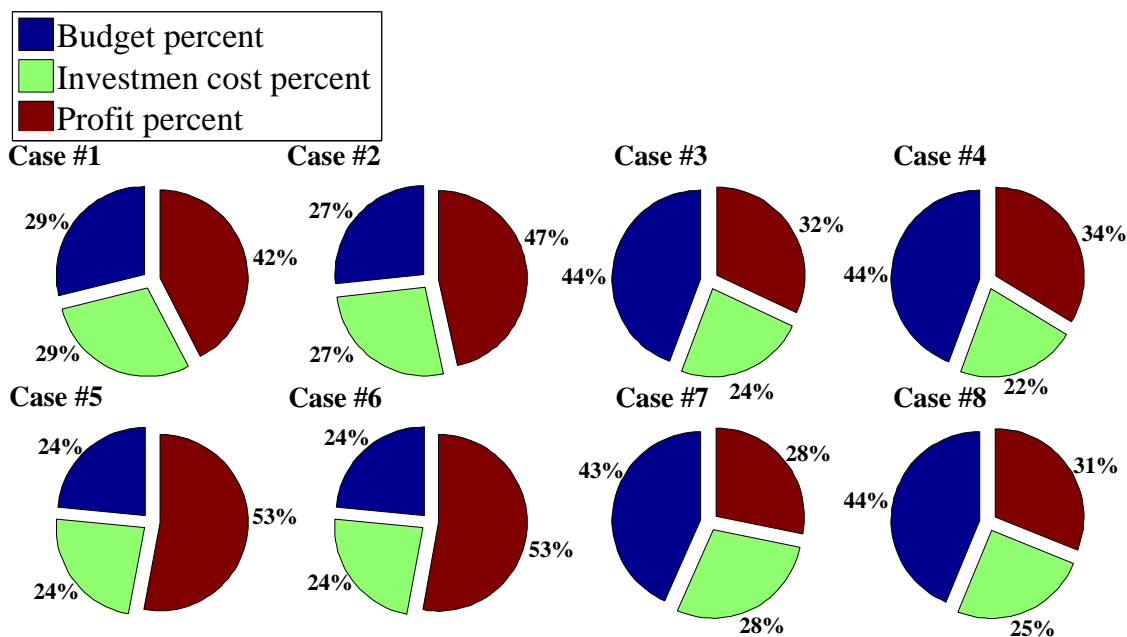


Figure 9. The percent related to the budget, investment cost and total net profit for each case.

6. Conclusions

This paper has presented a model for the expansion planning of wind resources in power systems at a multi-stage horizon. In this paper, the power system consists of a combination of fossil fuel technologies and wind resources for investment. Real case studies were considered and analyzed. The features of the proposed model and simulation results led to following conclusions:

- It can be seen that the percentage profit decreases as a result of increasing the available budget for both static and dynamic planning. At a lower budgetary level, the percentage profit yielded by the dynamic approach is more than that of the static approach so that the investment cost of the dynamic approach is less than the static. However, when the budgetary level is higher, the percentage profit in the static approach exceeds that of the dynamic approach while the static approach has a lower investment cost. The effect of a subsidy is to increase investor profit if the subsidy encourages investment on the wind technologies. In addition, the investment cost decreases in these cases. It can be seen that the total investor contribution has been increased in the dynamic approach with respect to the static one. Moreover, using the dynamic versus static approach in the planning of generation capacity leads to accurate and realistic results in the expansion planning.
- Additional work is underway to represent the strategic behaviour of market participants other than wind and new thermal producers. The proposed model can be adapted to consider the impact of transmission expansion plans, availability of gas transmission networks, tax policy, DSM plans and uncertainty in the demand growth.

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Nomenclature

Indices

w	index for scenario
y/y'	indexes for stage (year)
t	index for demand blocks
s/i/j	indexes for new base or peak units/existing generation unit and demand
h/l	investment capacity of new base or peak unit s/wind power at bus n (MW)
n/m	indexes for bus

Acronyms

N_t^h	weight of demand block t in year y
γ	weight of scenario w in demand block t
k_s^{TH}/c_n^{inv}	annualized investment cost of base or peak units/wind power (€/MW)
c_n^{inv}	investment cost of wind power at bus n
X_n^{Wmax}	maximum wind capacity that can be installed at bus n
X_{sh}^{Th}/X_{nl}^W	option h/l for investment capacity of new base or peak units s/wind power at bus n (MW)
p_i^{ESmax}	capacity of existing generation unit i of strategic producer (MW)
$d_{yjt看w}$	load of demand j in block t and year y (MW)
CS_s^{TH}/CS_i^{ES}	price offered by new base or peak units/existing unit producer (€/MWh)
B_{nm}	susceptance of line n-m (p.u.)
F_{nm}^{max}	transmission capacity of line n-m (MW)
f	Discount rate
S	Subsidy percent

Decision variables

X_{ys}^{TH}/X_{yn}^W	capacity investment of new unit s/wind power at bus n (MW)
u_{ysh}^{TH}/u_{ynl}^W	binary variable that is equal to 1 if the h/lth investment option determines the base or peak unit/wind power is selected in year y
$X_{yy's}^{THY}/X_{yy'n}^{WY}$	available capacity of new unit s/wind power at bus n in year y', in the years after the installation in year y (MW)
$p_{ystw}^{TH}/p_{yitw}^{ES}/p_{yn,tw}^W$	power produced by new base or peak units s/existing unit i/wind power at bus n, in year y, demand block t and scenario w (MW)
$p_{ystw}^{TH}/p_{yitw}^{ES}/p_{yn,tw}^W$	power produced by new base or peak units s/wind power at bus n, in year y', in the years after the installation in year y (MW)
$CS_{Syy'}^{THY}$	price offered by new base or peak units producer a, in year y', In the years after the installation in year y (€/MWh)
θ_{ytnw}	voltage angle of bus n, in year y, demand block t and scenario w

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